Minnesota Value of Solar: Methodology

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Executive Summary

Minnesota passed legislation[1] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (“VOS”) tariff as an alternative to net metering and as a rate identified for community solar gardens. The Department of Commerce (“Commerce”) was assigned the responsibility of developing and submitting the VOS methodology to the PUC by January 31, 2014. Utilities who adopt the VOS will be required to follow this methodology when calculating the VOS rate. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology.

The present document provides the draft methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input, and guidance from Commerce. It includes a detailed example calculation for each step of the calculation.

The resulting VOS represents the “value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value.” Solar customers will be billed for all usage under their existing applicable tariff, but will receive a VOS credit for gross solar energy production.

The VOS is the sum of several value components each calculated separately using procedures described in this document. As illustrated in Figure ES-1, the final calculation of the distributed PV value includes a base economic value, a load match factor (for capacity related components), and a loss savings factor as applicable at the component level. For example, the distribution capacity value will only include loss savings associated with the distribution system, but the savings in fuel costs will include both transmission and distribution loss savings.

Figure ES-1. Economic value, load match, loss savings, and distributed PV value.

	Economic Value ($/kWh)	X	Load Match (No Losses) (%)	X	(1	+	Distributed Loss Savings (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	E1						DLS-Energy			D1
Avoided O&M Cost	E2						DLS-Energy			D2
Avoided Generation Capacity Cost	E3		ELCC				DLS-ELCC			D3
Avoided Reserve Capacity Cost	E4		ELCC				DLS-ELCC			D4
Avoided Transmission Capacity Cost	E5		ELCC				DLS-ELCC			D5
Avoided Distribution Capacity Cost	E6		PLR				DLS-PLR			D6
Avoided Environmental Cost	E7						DLS-Energy			D7
										Value of Solar

The table facilitates transparency and stakeholder understanding by explicitly stating results by component and by separating the economic and technical factors, including the relative magnitude of load match and loss savings.

[1] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

The methodology results in a VOS credit schedule for a 25-year term, the assumed life of a PV resource. Credits are denominated in dollars per unit energy produced ($/kWh). The value is fixed as a levelized value, but also calculated in equivalent inflation-adjusted rates based on the assumed general escalation rate. The methodology includes a procedure for calculating the inflation-adjusted rates in $/kWh that would be incorporated into the VOS tariff.

The methodology includes:

- A standard PV rating convention
- Methods for creating a fleet-level PV production shape, representing the aggregate output of all PV systems in the service territory and used as the proxy for a marginal PV resource
- Requirements for calculating marginal loss savings for the transmission and distribution systems to be included in the VOS rate calculation
- Methods for performing technical calculations for avoided energy, effective generation capacity (ELCC) and effective distribution capacity (PLR)
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Introduction

Background

Minnesota passed legislation[2] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar ("VOS") tariff as an alternative to net metering and as a rate identified for community solar gardens. The Department of Commerce ("Commerce") was assigned the responsibility of developing and submitting the VOS methodology to the PUC by January 31, 2014. Utilities who adopt the VOS will be required to follow this methodology when calculating the VOS rate. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology.

The present document provides the draft methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input, and guidance from Commerce.

Framework

Solar customers will be billed for all usage under their existing applicable tariff, but will receive a VOS credit for gross solar energy production. Billing will reflect the applicable rate schedule, and the VOS credit will reflect "the value to the utility, its customers, and society for operating distributed solar photovoltaic resources interconnected to the utility system and operated by customers primarily for meeting their own energy needs."

Separation of Usage and Production

Separating usage (charges) from production (credits) simplifies the rate process for several reasons:

- Customers will be billed for all usage. Energy derived from the PV systems will not be used to offset ("net") usage prior to calculating charges. This will ensure that utility infrastructure costs will be recovered by the utilities as anticipated in the design of the usage rate.

- The utility will provide all energy consumed by the customer. Standby charges are not permitted under a VOS rate.

- The rates for usage can be adjusted in future ratemaking if necessary to allow the utility to recover costs of societal benefits.

[2] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

Distributed PV Value

The VOS is the sum of several value components each calculated separately using procedures defined in this methodology. As illustrated in Figure 1, the final calculation of the distributed PV value includes a base economic value, a load match factor (for capacity related values), and a loss savings factor, as applicable at the component level. For example, the distribution capacity value will only include loss savings associated with the distribution system, but the savings in fuel costs will include both transmission and distribution loss savings.

Figure 1. Economic value, load match, loss savings, and distributed PV value.

	Economic Value ($/kWh)	X	Load Match (No Losses) (%)	X	(1 +	Distributed Loss Savings (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	E1					DLS-Energy			D1
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Avoided Generation Capacity Cost	E3		ELCC			DLS-ELCC			D3
Avoided Reserve Capacity Cost	E4		ELCC			DLS-ELCC			D4
Avoided Transmission Capacity Cost	E5		ELCC			DLS-ELCC			D5
Avoided Distribution Capacity Cost	E6		PLR			DLS-PLR			D6
Avoided Environmental Cost	E7					DLS-Energy			D7
									Value of Solar

The table facilitates transparency and stakeholder understanding by explicitly stating results by component and by separating the economic and technical factors, including the relative magnitude of load match and loss savings.

VOS Term

The methodology results in a VOS credit schedule for a 25-year term, the assumed life of a PV resource. Credits are denominated in dollars per unit energy produced ($/kWh). The value is fixed in real terms, but is also calculated in equivalent nominal (inflation-adjusted) terms based on the assumed general escalation rate. The methodology includes a procedure for calculating the nominal rate table. This is a list of 25 annual rates in $/kWh that would be incorporated into the VOS tariff.

VOS Update Frequency

The VOS will be adjusted each year, and the results applicable to all customers entering the tariff during the given year. Customers who have already entered into the tariff in a previous year will not be affected by these annual adjustments.

Commerce may also update the methodology to use the best available practices, as necessary.

Solar Penetration

The methodology includes two measures of effective capacity (ELCC and PLR, described later). Both of these measures are dependent upon the installed capacity of PV relative to load (the "penetration level"). Only the current level of penetration is included based upon a load match analysis of a defined Load Analysis Period. Consequently the capacity-related value components will reflect the current level of PV penetration.

Future penetration levels will be considered in future adjustments to the VOS tariff. The effective capacity will be re-calculated as part of the future adjustment using more recent load data. To the extent that PV penetration increases in the future calculation, the future VOS rate will reflect that higher penetration.

Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. However, this methodology assumes that these occur during non-solar hours or that that overall impact of displaced coal is small relative to displaced natural gas.

Selection of VOS Components

Table 1 presents the VOS components selected by Commerce; column two lists the cost basis for each component. Table 2 presents the VOS components that were considered but not selected. Selections were made based on requirements and guidance in the enabling statute and were informed by the full set of stakeholder comments (included comments from Minnesota utilities, local and national solar and environmental organizations, local solar manufacturers and installers, and private parties) and workshop discussions. Stakeholders participated in three public workshops and provided comments through workshop panels, through workshop Q&A sessions, and through written comments.

Table 1. VOS components that will be included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Avoided Fuel Cost	Energy market costs (portion attributed to fuel).	Required (energy)	Includes cost of long-term price risk
Avoided Plant O&M Cost	Energy market costs (portion attributed to O&M).	Required (energy)	
Avoided Generation Capacity Cost	Capital cost of generation to meet peak load.	Required (capacity)	

Avoided Reserve Capacity Cost	Capital cost of generation to meet planning margins and ensure reliability.	Required (capacity)	
Avoided Transmission Capacity Cost	Capital cost of transmission.	Required (transmission capacity)	
Avoided Distribution Capacity Cost	Capital cost of distribution.	Required (delivery)	
Avoided Environmental Cost	Externality costs.	Required (environmental)	
Voltage Control	Cost to regulate distribution (future inverter designs)		Future (TBD)
Integration Cost[3]	Added cost to regulate system frequency with variable solar.		Future (TBD)

Table 2. VOS components that will not be included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Credit for Local Manufacturing/ Assembly	Local tax revenue tied to net solar jobs	Optional (identified in legislation)	
Market Price Reduction	Cost of wholesale power reduced according to reduction in demand.		
Disaster Recovery	Cost to restore local economy (requires energy storage and islanding inverters)		

The definition and selection of VOS components were based on the following considerations.

- Components corresponding to minimum statutory requirements are included. These account for the "value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."

[3] This is not a value, but a cost. It would reduce the VOS rate if included.

- Environmental costs are included as a required component and are based on existing Minnesota and EPA externality costs.
- Avoided fuel costs are based on long-term risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is passed from the utility to customers through fuel price adjustments.
- Credit for systems installed at high value locations (identified in the legislation as an option) is included as an option of the utility. It is not a separate VOS component but rather is implemented using a location-specific distribution capacity value (the component most affected by location). This is addressed in the Distribution Capacity Cost section.
- Voltage control and solar integration (a cost) are kept as “placeholder” components for future years. Methodologies are not provided, but these components may be developed for the future. Voltage control benefits are anticipated but will first require changes to national interconnection standards. Solar integration costs are expected to be small, but possibly measureable. Further research will be required on this topic.
- Non-required components were selected only if they were based on known and measurable evidence of the cost or benefit of solar operation to the utility.

VOS Example Calculation

Throughout this document, a VOS calculation example is provided to facilitate understanding of the methodology. The example is purely for illustration purposes and is not intended to set expectations of utility-specific VOS results.

Required Transparency Elements

The methodology incorporates two presentation elements that are to be included in the applications to the PUC for VOS tariffs. These are designed to improve transparency and facilitate understanding among stakeholders and regulators:

- *VOS Data Table*. Utilities will provide a list of the input assumptions identified in Table 3. In the table, the numeric parameters correspond to the example VOS calculation, and the utilities would provide values corresponding to their systems. The purpose of the VOS Data Table is to provide all stakeholders with the means to independently calculate the VOS and provide a means for directly comparing input assumptions among utilities. Terms are described more fully in Table 6.
- *VOS Levelized Calculation Chart*. Utilities will create a chart in the format shown in Figure 2. This chart includes key economic, load-match, and loss savings by value component.

Fixed Assumptions

Table 4 and Table 5 present fixed assumptions to be applied for all 2014 VOS rates, common to all utilities, as determined by Commerce. These may be updated in future years as necessary for application to future VOS adjustments. Table 5 is described in more detail in the Avoided Environmental Cost section. Terms are described more fully in Table 6.

Table 3. (EXAMPLE DATA) VOS Data Table— required, utility specific. These parameters are used for the example calculations.

	Input Data	Units			Input Data	Units
Economic Factors				**Power Generation**		
Start Year for VOS applicability	2014			Peaking CT, simple cycle		
Discount rate (WACC)	8.00%	per year		Installed cost	900	$/kW
				Heat rate	9,500	BTU/kWh
Load Match Analysis (see calculation methods)				Intermediate peaking CCGT		
ELCC (no loss)	40%	% of rating		Installed cost	1,200	$/kW
PLR (no loss)	30%	% of rating		Heat rate	6,500	BTU/kWh
Loss Savings - Energy	8%	% of PV output		Other		
Loss Savings - PLR	5%	% of PV output		Solar-weighted heat rate (see calc. method)	8000	BTU per kWh
Loss Savings - ELCC	9%	% of PV output		Fuel Price Overhead	$0.50	$ per MMBtu
				Generation life	50	years
PV Energy				Heat rate degradation	0.100%	per year
First year annual energy (see calc. method)	1800	kWh per kW-AC		O&M cost (first Year) - Fixed	$5.00	per kW-yr
				O&M cost (first Year) - Variable	$0.0010	$ per kWh
Transmission				O&M cost escalation rate	2.00%	per year
Capacity-related transmission capital cost	$200	$ per kW		Reserve planning margin	15%	
Years until new transmission capacity is needed	0	years				
Transmission life	60	years		**Distribution**		
Transmission capital cost escalation	2.00%	per year		Capacity-related distribution capital cost	$200	$ per kW
				Distribution capital cost escalation	2.00%	per year
				Peak load	5000	MW
				Peak load growth rate	1.00%	per year

See definitions in Table 6.

Table 4. Fixed assumptions to be used for 2014 VOS calculations – common to all utilities.

Fuel Prices						
Guaranteed NG fuel prices				**Environmental Externalities**		
2014	$3.93	$ per MMBtu		Environmental discount rate	3.00%	per year
2015	$4.12	$ per MMBtu		Environmental costs	(shown in separate table)	
2016	$4.25	$ per MMBtu				
2017	$4.36	$ per MMBtu		**Economic Assumptions**		
2018	$4.50	$ per MMBtu		General escalation rate	2.37%	per year
2019	$4.73	$ per MMBtu				
2020	$5.01	$ per MMBtu				
2021	$5.33	$ per MMBtu		**Treasury Yields**		
2022	$5.67	$ per MMBtu		1 Year	0.13%	
2023	$6.02	$ per MMBtu		2 Year	0.29%	
2024	$6.39	$ per MMBtu		3 Year	0.48%	
2025	$6.77	$ per MMBtu		5 Year	1.01%	
				7 Year	1.53%	
Guaranteed NG fuel price escalation	4.75%			10 Year	2.14%	
				20 Year	2.92%	
PV Assumptions				30 Year	3.27%	
PV degradation rate	0.50%	per year				
PV life	25	years				

See definitions in Table 6.

Table 5. Fixed environmental externality costs by year.

Year	Analysis Year	CO_2 Cost ($/MMBtu)	PM10 Cost ($/MMBtu)	CO Cost ($/MMBtu)	NO_x Cost ($/MMBtu)	Pb Cost ($/MMBtu)	Total Cost ($/MMBtu)
2014	0	1.939	0.066	0.000	0.012	0.000	2.017
2015	1	2.039	0.067	0.000	0.013	0.000	2.119
2016	2	2.142	0.069	0.000	0.013	0.000	2.224
2017	3	2.249	0.070	0.000	0.013	0.000	2.333
2018	4	2.360	0.072	0.000	0.014	0.000	2.446
2019	5	2.475	0.074	0.000	0.014	0.000	2.562
2020	6	2.594	0.076	0.000	0.014	0.000	2.684
2021	7	2.717	0.077	0.000	0.015	0.000	2.809
2022	8	2.844	0.079	0.000	0.015	0.000	2.939
2023	9	2.976	0.081	0.000	0.015	0.000	3.073
2024	10	3.113	0.083	0.000	0.016	0.000	3.212
2025	11	3.255	0.085	0.000	0.016	0.000	3.356
2026	12	3.401	0.087	0.000	0.016	0.000	3.505
2027	13	3.482	0.089	0.000	0.017	0.000	3.588
2028	14	3.637	0.091	0.000	0.017	0.000	3.746
2029	15	3.798	0.093	0.000	0.018	0.000	3.909
2030	16	3.964	0.096	0.000	0.018	0.000	4.078
2031	17	4.136	0.098	0.000	0.018	0.000	4.252
2032	18	4.314	0.100	0.000	0.019	0.000	4.433
2033	19	4.498	0.103	0.000	0.019	0.000	4.620
2034	20	4.688	0.105	0.000	0.020	0.000	4.813
2035	21	4.885	0.107	0.000	0.020	0.000	5.013
2036	22	5.089	0.110	0.000	0.021	0.000	5.219
2037	23	5.299	0.113	0.000	0.021	0.000	5.433
2038	24	5.517	0.115	0.000	0.022	0.000	5.654

See explanation in the Avoided Environmental Cost section.

Table 6. Input data definitions

Input Data	Used in Methodology Section	Definition
Guaranteed NG Fuel Prices	Avoided Fuel Cost	The annual average prices to be used when the utility elects to use the Futures Market option. These are not applicable when the utility elects to use options other than the Futures Market option. They are calculated as the annual average of monthly NYMEX NG futures[4], updated 8/27/2013.
Guaranteed NG Fuel Price Escalation	Avoided Fuel Cost	The escalation value to be applied for years in which futures prices are not available.
Fuel Price Overhead	Avoided Fuel Cost	The difference in cost of fuel as delivered to the plant and the cost of fuel as available in market prices. This cost reflects transmission, delivery, and taxes.
Treasury Yields	Economic Factors and PV Production	Yields for U.S. Treasuries, used as the basis of the risk-free discount rate calculation.[5]
Environmental Costs	Avoided Environmental Cost	The costs required to calculate environmental impacts of conventional generation. These are described more fully in the Avoided Environmental Cost section
Environmental Discount Rate	Avoided Environmental Cost	The societal discount rate corresponding to the EPA

[4] See for example http://futures.tradingcharts.com/marketquotes/NG.html.
[5] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

		future year cost data, used to calculate the present value of future environmental costs.
General escalation rate	Avoided Environmental Cost, Example Results	The annual escalation rate corresponding to the most recent 10 years of CPI index data[6], used to convert constant dollar environmental costs into current dollars and to translate levelized VOS into inflation-adjusted VOS.
ELCC (no loss), PLR (no loss)	Load Match	The "Effective Load Carrying Capability" and the "Peak Load Reduction" of a PV resource expressed as percentages of rated capacity (kW-AC). These are described more fully in the Load Match section.
Loss Savings (Energy, PLR, and ELCC)	Loss Savings	The additional savings associated with Energy, PRL and ELCC, expressed as a percentage PV production. These are described more fully in the Loss Savings section.
Start Year for VOS applicability	Multiple	This is the first year in which the VOS would apply and the first year for which avoided costs are calculated.
Discount rate (WACC)	Multiple	The utility's weighted average cost of capital, including interest on bonds and shareholder return.
First year annual energy	Avoided Energy, Economic Factors and PV Production	The annual PV production per kW-AC in the first year (before any degradation) of the marginal PV resource. This is calculated in the Avoided Energy Section and used in the Economic Factors and PV Production section.
PV Degradation	Economic Factors and PV Production	The reduction in percent per year of PV capacity and

[6] www.bls.gov

		PV energy due to degradation of the modules. The value of 0.5 percent is the median value of 2000 observed degradation rates.[7]
PV Life	Multiple	The assumed service life of PV. This value is also used to define the study period for which avoided costs are determined and the period over which the VOS rate would apply.
Capacity-related transmission capital cost	Avoided Transmission Capacity Cost	The cost per kW of new construction of transmission, including lines, towers, insulators, transmission substations, etc. Only capacity-related costs should be included.
Years until new transmission capacity is needed	Avoided Transmission Capacity Cost	This is used to test whether avoided costs for a given analysis year should be calculated and included.
Transmission life	Avoided Transmission Capacity Cost	The assumed service life of new transmission assets.
Transmission capital cost escalation	Avoided Transmission Capacity Cost	Used to adjust costs for future capital investments.
Solar-weighted heat rate	Avoided Fuel Costs	This is described in the described in the Avoided Fuel Costs section.
Reserve planning margin	Avoided Reserve Capacity Cost	The planning margin required to ensure reliability.
Installed cost and heat rate for CT and CCGT	Avoided Generation Capacity Cost	The capital costs for these units (including all construction costs, land, ad valorem taxes, etc.) and their heat rates.

[7] See D. Jordan and S. Kurtz, "Photovoltaic Degradation Rates – An Analytical Review," NREL, June 2012.

Generation life	Avoided Generation Capacity Cost	The assumed service life of new generation assets.
Heat rate degradation	Avoided Generation Capacity Cost	The percentage reduction in capacity per year.
O&M fixed costs	Avoided Plant O&M – Fixed	The costs to operate and maintain the plant that are not dependent on the amount of energy generated.
O&M variable costs	Avoided Plant O&M – Variable	The costs to operate and maintain the plant (excluding fuel costs) that are dependent on the amount of energy generated.
O&M cost escalation rate	Avoided Plant O&M – Fixed, Avoided Plant O&M – Variable	Used to calculate future O&M costs.
Capacity-related distribution capital cost	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
Distribution capital cost escalation	Avoided Distribution Capacity Cost	Used to calculate future distribution costs.
Peak Load	Avoided Distribution Capacity Cost	The utility peak load as expected in the year prior to the VOS start year.
Peak load growth rate	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.

Methodology: Technical Analysis

Rating Convention: kW-AC with losses

The selection of rating convention is somewhat arbitrary but must be used consistently throughout the VOS methodology. The VOS methodology uses kW-AC (or similarly MW-AC) that incorporates module derate effects, various system internal losses, and inverter efficiency. System ratings are determined as the sum of the AC ratings for each array in the system.

An array is defined in this context as a homogenous group of modules electrically connected to a single inverter or a homogenous group of inverters. All modules in an array must be of the same make and model, have the same tracking characteristics (fixed, single-axis or dual axis tracker), have the same tilt and azimuth, and be connected to a single inverter or a group of inverters that are all of the same make and model.

The AC rating for each array in the system is determined by multiplying the module quantity by the module PTC rating[8], as listed by the California Energy Commission (CEC)[9], times the CEC-listed inverter efficiency rating[10] times a loss factor to account for wiring, module mismatch, and other such losses. If no CEC module PTC rating is available, the module PTC rating should be calculated as 0.90 times the module STC rating[11]. If no CEC inverter efficiency rating is available, an inverter efficiency of 0.95 should be used. If no measured or design loss factor is available, 0.85 should be used. To summarize:

[Array Rating (kW-AC)] = [Module Quantity] x [Module PTC rating (kW)] x [Inverter Efficiency Rating] x [Loss Factor]

and

[PV System Rating (kW-AC)] = $\sum_{k=1}^{n}[\text{Array Rating (kW AC)}]^k$

[8] PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PTC are 1,000 Watts per square meter solar irradiance, 20 degrees C air temperature, and wind speed of 1 meter per second at 10 meters above ground level. PV manufacturers use Standard Test Conditions, or STC, to rate their PV products.

[9] CEC module PTC ratings for most modules can be found at http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php

[10] CEC inverter efficiency ratings for most inverters can be found at http://www.gosolarcalifornia.ca.gov/equipment/inverters.php

[11] PV manufacturers use Standard Test Conditions, or STC, to rate their PV products. STC are 1,000 Watts per square meter solar irradiance, 25 degrees C cell temperature, air mass equal to 1.5, and ASTM G173-03 standard spectrum.

Load Analysis Period

The technical analysis includes various hourly loss calculations, energy estimates, effective capacity calculations, and other calculations over a fixed Load Analysis Period. To capture the effects of seasonal changes in solar radiation, the load analysis period must cover a period of at least one year and preferably multiple years.

The data may start on any day of the year, and multiple years may be included, as long as all included years are contiguous and each included year is a complete one-year period. For example, valid load analysis periods may be 1/1/2012 0:00 to 12/31/2012 23:00 or 11/1/2010 0:00 to 10/31/2013 23:00.

Load Analysis Data

Three types of time series data are required to perform the technical analysis:

- Utility load (described in the ELCC calculations below)
- Distribution loads (described in the distribution section below)
- Fleet production shape (described below)

All three types of data must be provided as synchronized time-stamped hourly values of average power over the same period and corresponding to the same hourly intervals. Data must be available for every hour of the Load Analysis Period.

Data that is not in one-hour intervals must be converted to hourly data (for example, 15-minute meter data would have to be combined to 1-hour data). Also, data values that represent energy must be converted to average power.

If data is missing or deemed erroneous for any time period less than or equal to 24 hours, the values corresponding to that period may be replaced with an equal number of values from the same time interval on the previous or next day if it contains valid data. This data replacement method may be used provided that it does not materially affect the results.

Fleet Production Shape

The methodology requires an hourly solar profile, covering the Load Analysis Period, to be used in calculating effective capacity. This will help ensure that the non-dispatchable characteristic of solar is properly taken into account. The profile will be defined by the aggregate fleet of PV resources in the utility’s system. This profile is referred to as the Fleet Production Shape.

Fleet Production Shape data is created by first obtaining PV fleet production data (time-synchronized with load data), summing output for all systems in the fleet, then dividing the production for each hour by the fleet's combined AC rating. Because the Fleet Production Shape data is used in load analysis, it must satisfy the requirements identified in the Load Analysis Period and Load Analysis Data sections.

Aggregate Production Data

Aggregate production data for the fleet can be obtained using any one of the following three options:

1. Actual Fleet - Metered Production. Fleet production data can be created by combining actual metered production data for every PV system in the utility service territory, provided that there are a sufficient number of systems installed to accurately derive a correct, representative PV Fleet Production Shape. Such metered data is to be gross PV output on the AC side of the system, but before local customer loads are subtracted (i.e., PV must be separately metered from load). Metered data from individual systems is then aggregated by summing the measured output for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

2. Actual Fleet, Simulated Production., The aggregate output of all distributed PV systems in the utility service territory can be modeled if metered data is not available using PV system technical specifications and hourly irradiance and temperature data. These systems must be deployed in sufficient numbers to accurately derive a correct, representative PV Fleet Production Shape. Modeling must take into account the system's location and each array's tracking capability (fixed, single-axis or dual-axis tracking), orientation (tilt and azimuth), module PTC ratings, inverter efficiency and power ratings, other loss factors and the effect of temperature on module output. Technical specifications for each system must be available to enable such modeling. Modeling must also make use of location-specific, time-correlated, measured or satellite-derived plane of array irradiance data. Ideally, the software will also support modeling of solar obstructions.

   To make use of this option, start by obtaining detailed system specifications for every PV system in the utility's service territory. At a minimum, system specifications must include:
   1. Location (either exact street address or latitude and longitude)
   2. For each array in the system (see the section on Rating Conventions)
      - Total Array rating (kW-AC) using the rating conventions described in this document ***or*** Module CEC-PTC rating, Module Quantity, Inverter CEC Efficiency rating, Inverter AC Power rating
      - Array Tracking
      - Array Tilt
      - Array Azimuth

After simulating the power production for each system for each hour in the Load Analysis Period, power production must be aggregated by summing the power values for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

3. Load-based Fleet, Simulated Production. If neither metered production data nor detailed PV system specifications are available, a diverse set of PV resources can be estimated by simulating groups of systems at major load centers in the utility's service territory with some assumed fleet configuration. To use this method, start by identifying one or more of the largest load centers in the utility service territory. If a single load center accounts for a high percentage of the utility's total load, a single location will suffice. If there are several large load centers in the territory, groups of systems can be created at each location with capacities proportional to the load in that area.

   For each location, simulate multiple systems, each rated in proportion to the expected capacity, with azimuth and tilt angles such as the list of systems presented in Table 7. Note that the list of system configurations should represent the expected fleet composition.

Table 7. (EXAMPLE) Azimuth and tilt angles

System	Azimuth	Tilt
1	90	20
2	135	15
3	135	30
4	180	0
5	180	15
6	180	25
7	180	35
8	235	15
9	235	30
10	270	20

   Simulate each of the PV systems for each hour in the Load Analysis Period. Aggregate power production for the systems is obtained by summing the power values for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

   PV system ratings at a given location may be weighted according to load at each load center, if this is believed to give greater accuracy of geographical distribution.

   Regardless of location count and location weighting, the total fleet rating is taken as the sum of the individual system ratings.

Fleet Production Shape

After obtaining Aggregate Fleet Production data, divide the power value for each hour by the total combined AC rating of all systems used to create the Fleet Production Shape data. The units of this time series are average kW per kW-AC.

Marginal PV Resource

The marginal PV resource used for load analysis purposes is a 1 kW-AC system with an hourly production time series corresponding to the Fleet Production Shape.

Load Match Analysis

Capacity-related benefits are time dependent, so it is necessary to evaluate the effectiveness of PV in supporting loads during the critical peak hours. Two different measures of effective capacity are used:

- Effective Load Carrying Capability (ELCC)
- Peak Load Reduction (PLR)

Effective Load Carrying Capability (ELCC)

The ELCC is a measure of effective capacity based on an hourly loss of load probability (LOLP) analysis in which solar output during hours of highest load are weighted most heavily. The exact weighting is based on the fleet production and the time-synchronized system load. The ELCC is the load match figure applied to generation capacity, reserve capacity, generation fixed O&M, and transmission capacity values (see Figure 1).

The preferred ELCC methodology is a publicly available method that can be audited by any party as described below. The utility may alternatively calculate the ELCC using internal planning tools if the methodology and results have been reviewed by stakeholders and accepted in prior Minnesota Public Utility Commission Proceeding. However, if the internal tools are used, the calculations must use time-synchronized load and Fleet Production Shape data, and must be calculated for the two loss cases (with losses and without losses as described in the Loss Analysis section).

The preferred method is as follows. The ELCC is the result that makes the LOLP with the variable PV resource equal to the LOLP with a constant resource.[12]

- [12] Hoff, T. Calculating Photovoltaics' Value: A Utility Perspective, IEEE Transactions on Energy Conversion (Volume:3 , Issue: 3), Sept. 1988.

$$ELCC = m \ln \left\{ \frac{\sum_{h=1}^{\mathrm{N}} exp\left[-\frac{(Peak\ Generation - Original\ Hourly\ Generation_h)}{m}\right]}{\sum_{h=1}^{\mathrm{N}} exp\left[-\frac{(Peak\ Generation - New\ Hourly\ Generation_h)}{m}\right]} \right\} \tag{1}$$

where *Peak Generation* is the generation during the peak hour (MW) without PV, *Original Hourly Generation* is the hourly generation as measured, *New Hourly Generation* is the new generation with the marginal PV resource, and *m* is the utility Garver characteristic.

Original Hourly Generation should not be adjusted to account for existing PV production prior to its use in equation (1). The shape of the Original Hourly generation will reflect the current PV penetration level.

New Hourly Generation is the difference of the *Original Hourly Generation* and the effect of the marginal PV resource defined by the Fleet Production Shape (i.e., hourly generation reduced by PV). This value will either include the effect of loss savings or not, as described in the Loss Analysis section.

The utility Garver characteristic may be calculated by the utility. If this is not available, then it may be approximated as 5% of the peak generation.

ELCC is then expressed as a percentage number by dividing by the rating of the marginal PV resource (i.e., 1 kW-AC).

The ELCC percentage is applied to various components (see Figure 1).

Peak Load Reduction (PLR)

The PLR is defined as the maximum distribution load over the Load Analysis Period (without the marginal PV resource) minus the maximum distribution load over the Load Analysis Period (with the marginal PV resource). The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). The marginal PV resource is assumed to have production corresponding with the Fleet Production Shape.

This calculation will either include the effect of losses or not, as described in the Loss Analysis section.

In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

PLR is then expressed as a percentage number by dividing by the rating of the marginal PV resource (i.e., 1 kW-AC).

The PLR percentage is applied to the distribution capacity component (see Figure 1).

First Year Avoided Energy

The First Year Avoided Energy (kWh per year) is the difference in required generation to meet demand:

$$First\ YearAvoidedEnergy = \frac{\sum Original\ Generation_h - \sum New\ Generation_h}{NumberOfYearsInLoadAnalysisPeriod} \tag{2}$$

Loss Analysis

The capacity and energy technical quantities— ELCC, PLR, and Avoided Energy— are to be calculated twice: first by including the effects of avoided marginal losses and second by excluding them. Loss savings are later calculated as described in the following section using these two sets of results.

For example, the ELCC would first be calculated by including avoided transmission and distribution losses. Second, the ELCC would be re-calculated assuming no losses, i.e., as if the marginal PV resource was a central (not distributed) resource.

In calculating avoided marginal losses, the analysis must satisfy the following requirements:

1. Avoided losses are to be calculated on an hourly basis over the Load Analysis Period. The avoided losses are to be calculated based on the generation (and import) power during the hour and the expected output of the marginal PV resource during the hour.

2. The marginal PV resource corresponds to the Fleet Production Shape described in a previous section. Its shape must be time-synchronized with generation load. For example, when evaluating the hour ending 12:00 on June 1, 2012, measured generation data must be taken for that hour. Similarly, the Fleet Production Shape must be based on measured data (irradiance or PV power output) from the hour ending 12:00 on June 1, 2012. Data representing typical conditions based on previous years measurements will not be used for either generation or PV.

3. Avoided losses in the transmission system and distribution system are to be evaluated separately using distinct loss factors based on the most recent study data available.

4. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the marginal PV resource and the case with the marginal PV resource. Avoided average hourly losses are not calculated. For example, if the marginal PV resource were to produce 1 kW of power in an hour in which total customer load were 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.

5. Distribution losses should be based on the power entering the distribution system, after transmission losses.

6. Avoided transmission losses should take into account not only the marginal PV generation, but also the avoided marginal distribution losses.

7. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.

8. Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load. For example, the total load-related losses during an hour with a load of 2X would be approximately 4 times the total load-related losses during an hour with a load of only X.

Loss Savings

Loss savings are realized when PV is located in the distribution system at the point of end use. They are applied to value components. For example, the amount of fuel saved will not only include the fuel required to produce the energy that is consumed by the customer, but also the energy that would have been lost traversing the transmission and distribution systems.

The ELCC Loss Savings percentage is determined by setting the ELCC with marginal loss savings equal to the product of the ELCC without marginal loss savings and one plus the ELCC loss savings and then solving:

$$ELCC_{WithLosses} = ELCC_{WithoutLosses}(1 + LossSavings_{ELCC}) \tag{3}$$

This equation can be rearranged with the result:

$$LossSavings_{ELCC} = \frac{ELCC_{WithLosses}}{ELCC_{WithoutLosses}} - 1 \tag{4}$$

Similarly, the PLR Loss Savings is defined as:

$$LossSavings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \tag{5}$$

and the Energy Loss Savings is defined as:

$$LossSavings_{Energy} = \frac{AvoidedEnergy_{WithLosses}}{AvoidedEnergy_{WithoutLosses}} - 1 \tag{6}$$

Methodology: Economic Analysis

The economic analysis is initially performed as if PV was centrally-located (without loss-saving benefits of distributed location) and with output perfectly correlated to load. Real-world adjustments are made later in the final VOS summation by including the results of the loss savings and load match analyses.

Economic Factors and PV Production

The assumed life of PV is 25 years, and this is the duration of the economic analysis period.

By convention, the analysis year 0 corresponds to the year in which the VOS tariff will begin. For example, during the year 2013 a VOS analysis might be done for customers who enter the tariff between January 1, 2014 and December 31, 2014. In this case, 2014 is year 0, 2015 is year 1, etc.

For each year *i*, a discount factor is given by

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \tag{7}$$

The *DiscountRate* is the utility Weighted Average Cost of Capital (see Table 3).

Similarly, a risk-free discount factor is given by:

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \tag{8}$$

The *RiskFreeDiscountRate* is based on the yields of current Treasury securities[13] of 1, 2, 3, 5, 7, 10, 20, and 30 year maturation dates.

Finally, an environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \tag{9}$$

PV production in kWh per kW-AC for year *i* for the marginal PV resource, taking into account degradation, is given by:

$$PVProduction_i = PVProduction_0 \times (1 - \mathrm{PVDegradationRate})^i \tag{10}$$

[13] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

where PVDegradationRate is the annual rate of PV degradation and $PVProduction_0$ is the avoided annual generation under no loss conditions. $PVProduction_0$ may also be obtained by summing the hourly Fleet Production Shape and dividing by the number of years in the load analysis period. PVDegradationRate is assumed to be 0.5% per year.

PV capacity in year *i* for a marginal PV resource, taking into account degradation, equals:

$$PVCapacity_i = (1 - \text{PVDegradationRate})^i \qquad (11)$$

Avoided Fuel Cost

PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation. Furthermore, the PV system is assumed to have a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract.

The methodology provides for three options to accomplish this:

- *Futures Market*. This option is described in detail below, and is based on the NYMEX NG futures with a 4.75% escalation[14] for years beyond the 12-year trading period.

- *Long Term Price Quotation*. This option is identical to the above option, except the input pricing data is based on an actual price quotation from an AA-rated NG supplier to lock in prices for the 25-year guaranteed period.

- *Utility-guaranteed Price*. This is the 25-year fuel price that is guaranteed by the utilities. Tariffs using the utility guaranteed price will include a mechanism for removing the usage fuel adjustment charges and provide fixed prices over the term.

Table 8 presents the calculation of the economic value of avoided fuel costs.

For the Futures Market option, Guaranteed NG prices are calculated as follows. Prices for the first 12 years are based on NYMEX futures, with each monthly price averaged to give a 12-month average in $ per MMBtu. Prices for years beyond this NYMEX limit are calculated by applying the assumed annual NYMEX price escalation. An assumed fuel price overhead amount, escalated by year using the assumed NYMEX price escalation, is added to the fuel price to give the burnertip fuel price.

The first-year solar-weighted heat rate is calculated as follows:

[14] Based on NYMEX price analysis conducted by CPR for Austin Energy, 2014, see http://www.cleanpower.com/wp-content/uploads/2014-VOS-at-Austin-Energy-Results-2013-10-21.pdf.

$$SolarWeighedHeatRate_0 = \frac{\sum HeatRate_j \times FleetProduction_j}{\sum FleetProduction_j} \quad (12)$$

where the summation is over all hours *j* of the load analysis period, *HeatRate* is the actual heat rate of the plant on the margin, and *FleetProduction* is the Fleet Production Shape time series.

The solar-weighted heat rate for future years is calculated as:

$$SolarWeighedHeatRate_i = SolarWeighedHeatRate_0 \times (1 - \mathrm{HeatRateDegradationRate})^i \quad (13)$$

The utility price in year *i* is:

$$UtilityPrice_i = \frac{BurnertipFuelPrice_i \times SolarWeighedHeatRate_i}{10^6} \quad (14)$$

where the burnertip price is in $ per MMBtu and the heat rate is in Btu per kWh.

Utility cost is the product of the utility price and the per unit PV production. These costs are then discounted using the risk free discount rate and summed over all years. The VOS price (shown in red in Table 8) is the levelized amount that results in the same discounted amount as the utility price for the Avoided Fuel Cost component.

Avoided Plant O&M – Fixed

Economic value calculations for fixed plant O&M are presented in Table 9. The first year fixed value is escalated at the O&M escalation rate for future years.

Table 8. (EXAMPLE) Economic Value of Avoided Fuel Costs.

Year	Guaranteed NG Price ($/MMBtu)	Burnertip NG Prrice ($/MMBtu)	Heat Rate (Btu/kWh)	Prices Utility ($/kWh)	Prices VOS ($/kWh)	p.u. PV Production (kWh)	Costs Utility ($)	Costs VOS ($)	Discount Factor (risk free)	Disc. Costs Utility ($)	Disc. Costs VOS ($)
2014	$3.93	$4.43	8000	$0.035	$0.060	1,800	$64	$108	1.000	$64	$108
2015	$4.12	$4.65	7992	$0.037	$0.060	1,791	$67	$107	0.999	$66	$107
2016	$4.25	$4.79	7984	$0.038	$0.060	1,782	$68	$107	0.994	$68	$106
2017	$4.36	$4.93	7976	$0.039	$0.060	1,773	$70	$106	0.986	$69	$104
2018	$4.50	$5.10	7968	$0.041	$0.060	1,764	$72	$105	0.971	$70	$102
2019	$4.73	$5.36	7960	$0.043	$0.060	1,755	$75	$105	0.951	$71	$100
2020	$5.01	$5.67	7952	$0.045	$0.060	1,747	$79	$104	0.927	$73	$97
2021	$5.33	$6.02	7944	$0.048	$0.060	1,738	$83	$104	0.899	$75	$93
2022	$5.67	$6.39	7936	$0.051	$0.060	1,729	$88	$103	0.872	$76	$90
2023	$6.02	$6.78	7928	$0.054	$0.060	1,721	$92	$103	0.842	$78	$87
2024	$6.39	$7.18	7920	$0.057	$0.060	1,712	$97	$102	0.809	$79	$83
2025	$6.77	$7.60	7912	$0.060	$0.060	1,703	$102	$102	0.786	$80	$80
2026	$7.09	$7.96	7905	$0.063	$0.060	1,695	$107	$101	0.762	$81	$77
2027	$7.42	$8.34	7897	$0.066	$0.060	1,686	$111	$101	0.737	$82	$74
2028	$7.78	$8.73	7889	$0.069	$0.060	1,678	$116	$100	0.713	$82	$71
2029	$8.15	$9.15	7881	$0.072	$0.060	1,670	$120	$100	0.688	$83	$69
2030	$8.53	$9.58	7873	$0.075	$0.060	1,661	$125	$99	0.663	$83	$66
2031	$8.94	$10.04	7865	$0.079	$0.060	1,653	$131	$99	0.637	$83	$63
2032	$9.36	$10.52	7857	$0.083	$0.060	1,645	$136	$98	0.612	$83	$60
2033	$9.81	$11.02	7849	$0.086	$0.060	1,636	$141	$98	0.587	$83	$57
2034	$10.27	$11.54	7842	$0.090	$0.060	1,628	$147	$97	0.563	$83	$55
2035	$10.76	$12.09	7834	$0.095	$0.060	1,620	$153	$97	0.543	$83	$53
2036	$11.27	$12.66	7826	$0.099	$0.060	1,612	$160	$96	0.523	$84	$50
2037	$11.81	$13.26	7818	$0.104	$0.060	1,604	$166	$96	0.504	$84	$48
2038	$12.37	$13.89	7810	$0.109	$0.060	1,596	$173	$95	0.485	$84	$46

Validation: Present Value	$1,947	$1,947

Table 9. (EXAMPLE) Economic value of avoided plant O&M – fixed.

				Prices			Costs			Disc. Costs	
Year	O&M Fixed	Utility Capacity	PV Capacity	Utility	VOS	p.u. PV Production	Utility	VOS	Discount Factor	Utility	VOS
	($/kW)	(p.u.)	(kW)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$5.00	1.000	1.000	$0.003	$0.003	1800	$5	$6	1.000	$5	$6
2015	$5.11	0.999	0.995	$0.003	$0.003	1791	$5	$6	0.926	$5	$6
2016	$5.21	0.998	0.990	$0.003	$0.003	1782	$5	$6	0.857	$4	$5
2017	$5.32	0.997	0.985	$0.003	$0.003	1773	$5	$6	0.794	$4	$5
2018	$5.43	0.996	0.980	$0.003	$0.003	1764	$5	$6	0.735	$4	$4
2019	$5.55	0.995	0.975	$0.003	$0.003	1755	$5	$6	0.681	$4	$4
2020	$5.66	0.994	0.970	$0.003	$0.003	1747	$6	$6	0.630	$3	$4
2021	$5.78	0.993	0.966	$0.003	$0.003	1738	$6	$6	0.583	$3	$3
2022	$5.91	0.992	0.961	$0.003	$0.003	1729	$6	$6	0.540	$3	$3
2023	$6.03	0.991	0.956	$0.003	$0.003	1721	$6	$6	0.500	$3	$3
2024	$6.16	0.990	0.951	$0.003	$0.003	1712	$6	$6	0.463	$3	$3
2025	$6.29	0.989	0.946	$0.004	$0.003	1703	$6	$6	0.429	$3	$2
2026	$6.42	0.988	0.942	$0.004	$0.003	1695	$6	$6	0.397	$2	$2
2027	$6.55	0.987	0.937	$0.004	$0.003	1686	$6	$6	0.368	$2	$2
2028	$6.69	0.986	0.932	$0.004	$0.003	1678	$6	$6	0.340	$2	$2
2029	$6.83	0.985	0.928	$0.004	$0.003	1670	$6	$6	0.315	$2	$2
2030	$6.97	0.984	0.923	$0.004	$0.003	1661	$7	$6	0.292	$2	$2
2031	$7.12	0.983	0.918	$0.004	$0.003	1653	$7	$6	0.270	$2	$1
2032	$7.27	0.982	0.914	$0.004	$0.003	1645	$7	$5	0.250	$2	$1
2033	$7.42	0.981	0.909	$0.004	$0.003	1636	$7	$5	0.232	$2	$1
2034	$7.58	0.980	0.905	$0.004	$0.003	1628	$7	$5	0.215	$2	$1
2035	$7.74	0.979	0.900	$0.004	$0.003	1620	$7	$5	0.199	$1	$1
2036	$7.90	0.978	0.896	$0.004	$0.003	1612	$7	$5	0.184	$1	$1
2037	$8.07	0.977	0.891	$0.005	$0.003	1604	$7	$5	0.170	$1	$1
2038	$8.24	0.976	0.887	$0.005	$0.003	1596	$7	$5	0.158	$1	$1

Validation: Present Value	$67	$67

Similarly, PV capacity has an initial value of one during the first year because it is applicable to PV systems installed in the first year. Note that effective capacity (load matching) is handled separately, and this table represents the "ideal" resource, as if PV were able to receive the same capacity credit as a fully dispatchable technology.

Fixed O&M is avoided only when the resource requiring fixed O&M is avoided. For example, if new generation is not needed for two years, then the associated fixed O&M is also not needed for two years. In the example calculation, generation is assumed to be needed for all years, so the avoided cost is calculated for all years.

The utility cost is the fixed O&M cost times the PV capacity divided by the utility capacity. Utility prices are the cost divided by the PV production. Costs are discounted using the utility discount factor and are summed over all years.

The VOS component value is calculated as before such that the discounted total is equal to the discounted utility cost.

Avoided Plant O&M – Variable

An example calculation of avoided plant O&M is displayed in Table 10. Utility prices are given in the VOS Data Table, escalated each year by the O&M escalation rate. As before, the per unit PV production is shown with annual degradation taken into account. The utility cost is the product of the utility price and the per unit production, and these costs are discounted. The VOS price of variable O&M is the levelized value resulting in the same total discounted cost.

Table 10. (EXAMPLE) Economic value of avoided plant O&M – variable.

Year	Prices		p.u. PV Production	Costs		Discount Factor	Disc. Costs	
	Utility	VOS		Utility	VOS		Utility	VOS
	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$0.001	$0.001	1,800	$2	$2	1.000	$2	$2
2015	$0.001	$0.001	1,791	$2	$2	0.926	$2	$2
2016	$0.001	$0.001	1,782	$2	$2	0.857	$2	$2
2017	$0.001	$0.001	1,773	$2	$2	0.794	$1	$2
2018	$0.001	$0.001	1,764	$2	$2	0.735	$1	$2
2019	$0.001	$0.001	1,755	$2	$2	0.681	$1	$1
2020	$0.001	$0.001	1,747	$2	$2	0.630	$1	$1
2021	$0.001	$0.001	1,738	$2	$2	0.583	$1	$1
2022	$0.001	$0.001	1,729	$2	$2	0.540	$1	$1
2023	$0.001	$0.001	1,721	$2	$2	0.500	$1	$1
2024	$0.001	$0.001	1,712	$2	$2	0.463	$1	$1
2025	$0.001	$0.001	1,703	$2	$2	0.429	$1	$1
2026	$0.001	$0.001	1,695	$2	$2	0.397	$1	$1
2027	$0.001	$0.001	1,686	$2	$2	0.368	$1	$1
2028	$0.001	$0.001	1,678	$2	$2	0.340	$1	$1
2029	$0.001	$0.001	1,670	$2	$2	0.315	$1	$1
2030	$0.001	$0.001	1,661	$2	$2	0.292	$1	$1
2031	$0.001	$0.001	1,653	$2	$2	0.270	$1	$1
2032	$0.001	$0.001	1,645	$2	$2	0.250	$1	$0
2033	$0.001	$0.001	1,636	$2	$2	0.232	$1	$0
2034	$0.001	$0.001	1,628	$2	$2	0.215	$1	$0
2035	$0.002	$0.001	1,620	$2	$2	0.199	$0	$0
2036	$0.002	$0.001	1,612	$2	$2	0.184	$0	$0
2037	$0.002	$0.001	1,604	$3	$2	0.170	$0	$0
2038	$0.002	$0.001	1,596	$3	$2	0.158	$0	$0

Validation: Present Value	**$24**	**$24**

Avoided Generation Capacity Cost

The solar-weighted capacity cost is based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate:

$$Cost = Cost_{CCGT} + (HeatRate_{PV} - HeatRate_{CCGT}) \times \frac{Cost_{CT} - Cost_{CCGT}}{HeatRate_{CT} - HeatRate_{CCGT}} \qquad (15)$$

Where $HeatRate_{PV}$ is the solar-weighted heat rate calculated in equation (12).

Using equation (15) with the CT/CCGT heat rates and costs from the example VOS Data Table, we calculated a solar-weighted capacity cost of $1,050 per kW. In the example, the amortized cost is $86 per kW-yr.

Table 11 illustrates how utility costs are calculated by taking into account the degrading heat rate of the marginal unit and PV. For example, in year 2015, the utility cost is $86 per kW-yr x 0.999 / 0.995 to give $85 for each unit of effective PV capacity. Utility prices are back-calculated for reference from the per unit PV production. Again, the VOS price is selected to give the same total discounted cost as the utility costs for the Generation Capacity Cost component.

Table 11. (EXAMPLE) Economic value of avoided generation capacity cost.

				Prices			Costs			Disc. Costs	
Year	Capacity Cost	Utility Capacity	PV Capacity	Utility	VOS	p.u. PV Production	Utility	VOS	Discount Factor	Utility	VOS
	($/kW-yr)	(p.u.)	(kW)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$86	1.000	1.000	$0.048	$0.048	1800	$86	$87	1.000	$86	$87
2015	$86	0.999	0.995	$0.048	$0.048	1791	$85	$86	0.926	$79	$80
2016	$86	0.998	0.990	$0.048	$0.048	1782	$85	$86	0.857	$73	$73
2017	$86	0.997	0.985	$0.048	$0.048	1773	$85	$85	0.794	$67	$68
2018	$86	0.996	0.980	$0.048	$0.048	1764	$84	$85	0.735	$62	$62
2019	$86	0.995	0.975	$0.048	$0.048	1755	$84	$84	0.681	$57	$57
2020	$86	0.994	0.970	$0.048	$0.048	1747	$84	$84	0.630	$53	$53
2021	$86	0.993	0.966	$0.048	$0.048	1738	$83	$84	0.583	$49	$49
2022	$86	0.992	0.961	$0.048	$0.048	1729	$83	$83	0.540	$45	$45
2023	$86	0.991	0.956	$0.048	$0.048	1721	$83	$83	0.500	$41	$41
2024	$86	0.990	0.951	$0.048	$0.048	1712	$82	$82	0.463	$38	$38
2025	$86	0.989	0.946	$0.048	$0.048	1703	$82	$82	0.429	$35	$35
2026	$86	0.988	0.942	$0.048	$0.048	1695	$82	$81	0.397	$32	$32
2027	$86	0.987	0.937	$0.048	$0.048	1686	$81	$81	0.368	$30	$30
2028	$86	0.986	0.932	$0.048	$0.048	1678	$81	$81	0.340	$28	$27
2029	$86	0.985	0.928	$0.048	$0.048	1670	$81	$80	0.315	$25	$25
2030	$86	0.984	0.923	$0.048	$0.048	1661	$80	$80	0.292	$23	$23
2031	$86	0.983	0.918	$0.049	$0.048	1653	$80	$79	0.270	$22	$21
2032	$86	0.982	0.914	$0.049	$0.048	1645	$80	$79	0.250	$20	$20
2033	$86	0.981	0.909	$0.049	$0.048	1636	$80	$79	0.232	$18	$18
2034	$86	0.980	0.905	$0.049	$0.048	1628	$79	$78	0.215	$17	$17
2035	$86	0.979	0.900	$0.049	$0.048	1620	$79	$78	0.199	$16	$15
2036	$86	0.978	0.896	$0.049	$0.048	1612	$79	$77	0.184	$14	$14
2037	$86	0.977	0.891	$0.049	$0.048	1604	$78	$77	0.170	$13	$13
2038	$86	0.976	0.887	$0.049	$0.048	1596	$78	$77	0.158	$12	$12

Validation: Present Value	$958	$958

Avoided Reserve Capacity Cost

An example of the calculation of avoided reserve capacity cost is shown in Table 12. This is identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin. In the example, the reserve capacity margin is 15%, so the utility cost for 2014 is calculated as

$86 per unit effective capacity x 15% = $13. The rest of the calculation is identical to the capacity cost calculation.

Table 12. (EXAMPLE) Economic value of avoided reserve capacity cost.

				Prices			Costs			Disc. Costs	
Year	Capacity Cost	Gen. Capacity	PV Capacity	Utility	VOS	p.u. PV Production	Utility	VOS	Discount Factor	Utility	VOS
	($/kW-yr)	(p.u.)	(kW)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$86	1.000	1.000	$0.007	$0.007	1800	$13	$13	1.000	$13	$13
2015	$86	0.999	0.999	$0.007	$0.007	1791	$13	$13	0.926	$12	$12
2016	$86	0.998	0.994	$0.007	$0.007	1782	$13	$13	0.857	$11	$11
2017	$86	0.997	0.986	$0.007	$0.007	1773	$13	$13	0.794	$10	$10
2018	$86	0.996	0.971	$0.007	$0.007	1764	$13	$13	0.735	$9	$9
2019	$86	0.995	0.951	$0.007	$0.007	1755	$13	$13	0.681	$9	$9
2020	$86	0.994	0.927	$0.007	$0.007	1747	$13	$13	0.630	$8	$8
2021	$86	0.993	0.899	$0.007	$0.007	1738	$13	$13	0.583	$7	$7
2022	$86	0.992	0.872	$0.007	$0.007	1729	$12	$12	0.540	$7	$7
2023	$86	0.991	0.842	$0.007	$0.007	1721	$12	$12	0.500	$6	$6
2024	$86	0.990	0.809	$0.007	$0.007	1712	$12	$12	0.463	$6	$6
2025	$86	0.989	0.786	$0.007	$0.007	1703	$12	$12	0.429	$5	$5
2026	$86	0.988	0.762	$0.007	$0.007	1695	$12	$12	0.397	$5	$5
2027	$86	0.987	0.737	$0.007	$0.007	1686	$12	$12	0.368	$4	$4
2028	$86	0.986	0.713	$0.007	$0.007	1678	$12	$12	0.340	$4	$4
2029	$86	0.985	0.688	$0.007	$0.007	1670	$12	$12	0.315	$4	$4
2030	$86	0.984	0.663	$0.007	$0.007	1661	$12	$12	0.292	$4	$3
2031	$86	0.983	0.637	$0.007	$0.007	1653	$12	$12	0.270	$3	$3
2032	$86	0.982	0.612	$0.007	$0.007	1645	$12	$12	0.250	$3	$3
2033	$86	0.981	0.587	$0.007	$0.007	1636	$12	$12	0.232	$3	$3
2034	$86	0.980	0.563	$0.007	$0.007	1628	$12	$12	0.215	$3	$3
2035	$86	0.979	0.543	$0.007	$0.007	1620	$12	$12	0.199	$2	$2
2036	$86	0.978	0.523	$0.007	$0.007	1612	$12	$12	0.184	$2	$2
2037	$86	0.977	0.504	$0.007	$0.007	1604	$12	$12	0.170	$2	$2
2038	$86	0.976	0.485	$0.007	$0.007	1596	$12	$12	0.158	$2	$2

Validation: Present Value	**$144**	**$144**

Avoided Transmission Capacity Cost

Avoided transmission costs are calculated the same way as avoided generation costs except transmission is assumed not to degrade over time (PV degradation is still accounted for). Table 13 shows the example calculation in which the cost for new transmission capacity is taken from Table 3. As with generation capacity, transmission capacity costs are only calculated for years in which transmission is needed. For example, if transmission capacity is not needed for two years, then the avoided costs would not be included in the first year.

Table 13. (EXAMPLE) Economic value of avoided transmission capacity cost.

Year	Capacity Cost ($/kW-yr)	Trans. Capacity (p.u.)	PV Capacity (kW)	Prices Utility ($/kWh)	Prices VOS ($/kWh)	p.u. PV Producti (kWh)	Costs Utility ($)	Costs VOS ($)	Discount Factor	Disc. Costs Utility ($)	Disc. Costs VOS ($)
2014	$16	1.000	1.000	$0.009	$0.009	1800	$16	$16	1.000	$16	$16
2015	$16	1.000	0.995	$0.009	$0.009	1791	$16	$16	0.926	$15	$15
2016	$16	1.000	0.990	$0.009	$0.009	1782	$16	$16	0.857	$14	$14
2017	$16	1.000	0.985	$0.009	$0.009	1773	$16	$16	0.794	$13	$13
2018	$16	1.000	0.980	$0.009	$0.009	1764	$16	$16	0.735	$12	$12
2019	$16	1.000	0.975	$0.009	$0.009	1755	$16	$16	0.681	$11	$11
2020	$16	1.000	0.970	$0.009	$0.009	1747	$16	$16	0.630	$10	$10
2021	$16	1.000	0.966	$0.009	$0.009	1738	$16	$16	0.583	$9	$9
2022	$16	1.000	0.961	$0.009	$0.009	1729	$16	$16	0.540	$8	$8
2023	$16	1.000	0.956	$0.009	$0.009	1721	$15	$15	0.500	$8	$8
2024	$16	1.000	0.951	$0.009	$0.009	1712	$15	$15	0.463	$7	$7
2025	$16	1.000	0.946	$0.009	$0.009	1703	$15	$15	0.429	$7	$7
2026	$16	1.000	0.942	$0.009	$0.009	1695	$15	$15	0.397	$6	$6
2027	$16	1.000	0.937	$0.009	$0.009	1686	$15	$15	0.368	$6	$6
2028	$16	1.000	0.932	$0.009	$0.009	1678	$15	$15	0.340	$5	$5
2029	$16	1.000	0.928	$0.009	$0.009	1670	$15	$15	0.315	$5	$5
2030	$16	1.000	0.923	$0.009	$0.009	1661	$15	$15	0.292	$4	$4
2031	$16	1.000	0.918	$0.009	$0.009	1653	$15	$15	0.270	$4	$4
2032	$16	1.000	0.914	$0.009	$0.009	1645	$15	$15	0.250	$4	$4
2033	$16	1.000	0.909	$0.009	$0.009	1636	$15	$15	0.232	$3	$3
2034	$16	1.000	0.905	$0.009	$0.009	1628	$15	$15	0.215	$3	$3
2035	$16	1.000	0.900	$0.009	$0.009	1620	$15	$15	0.199	$3	$3
2036	$16	1.000	0.896	$0.009	$0.009	1612	$14	$14	0.184	$3	$3
2037	$16	1.000	0.891	$0.009	$0.009	1604	$14	$14	0.170	$2	$2
2038	$16	1.000	0.887	$0.009	$0.009	1596	$14	$14	0.158	$2	$2

Validation: Present Value	**$179**	**$179**

Avoided Distribution Capacity Cost

Avoided distribution capacity costs may be calculated in either of two ways:

- System-wide Avoided Costs. These are calculated using utility-wide costs and lead to a VOS rate that is "averaged" and applicable to all solar customers. This method is described below in the methodology.

- Location-specific Avoided Costs. These are calculated using location-specific costs, growth rates, etc., and lead to location-specific VOS rates. This method provides the utility with a means for offering a higher-value VOS rate in areas where capacity is most needed (areas of highest value). The details of this method are site specific and not included in the methodology, however they are to be implemented in accordance with the requirements set for the below.

System-wide Avoided Costs

System wide costs and peak growth rates are determined using actual data from each of the last 10 years. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts using the percentages shown in Table 14.

Table 14. (EXAMPLE) Determination of deferrable costs.

Account	Account Name	Additions ($) [A]	Retirements ($) [R]	Net Additions ($) = [A] - [R]	Capacity Related?	Deferrable ($)
	DISTRIBUTION PLANT					
360	Land and Land Rights	13,931,928	233,588	13,698,340	100%	13,698,340
361	Structures and Improvements	35,910,551	279,744	35,630,807	100%	35,630,807
362	Station Equipment	478,389,052	20,808,913	457,580,139	100%	457,580,139
363	Storage Battery Equipment					
364	Poles, Towers, and Fixtures	310,476,864	9,489,470	300,987,394		
365	Overhead Conductors and Devices	349,818,997	22,090,380	327,728,617	25%	81,932,154
366	Underground Conduit	210,115,953	10,512,018	199,603,935	25%	49,900,984
367	Underground Conductors and Devices	902,527,963	32,232,966	870,294,997	25%	217,573,749
368	Line Transformers	389,984,149	19,941,075	370,043,074		
369	Services	267,451,206	5,014,559	262,436,647		
370	Meters	118,461,196	4,371,827	114,089,369		
371	Installations on Customer Premises	22,705,193		22,705,193		
372	Leased Property on Customer Premises					
373	Street Lighting and Signal Systems	53,413,993	3,022,447	50,391,546		
374	Asset Retirement Costs for Distribution Plant	15,474,098	2,432,400	13,041,698		
TOTAL		3,168,661,143	130,429,387	3,038,231,756		$ 856,316,173

Cost per unit growth ($ per kW) is calculated by taking all of the total deferrable cost for each year, adjusting for inflation, and dividing by the kW increase in peak annual load over the 10 years.

Future growth in peak load is assumed to be at the same rate as the last 10 years. It is calculated using the ratio of peak loads of the most recent year (year 10) and the peak load from the earlier year (year 1):

$$GrowthRate = \left(\frac{P_{10}}{P_1}\right)^{1/10} - 1 \qquad (16)$$

A sample economic value calculation is presented in Table 15. The distribution cost for the first year ($200 per kW in the example) is taken from the analysis of historical cost and growth as described above. This cost is escalated each year using the rate in the VOS Data Table.

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. The total discounted cost is calculated ($149M) and this is amortized over the 25 years.

Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

		Conventional Distribution Planning				Deferred Distribution Planning				Prices			Costs			Disc. Costs	
Year	Distribution Cost	New Dist. Capacity	Capital Cost	Disc. Capital Cost	Amortized	Def. Dist. Capacity	Def. Capital Cost	Disc. Capital Cost	Amortized	Utility	VOS	p.u. PV Production	Utility	VOS	Discount Factor	Utility	VOS
	($/kW)	(MW)	($M)	($M)	$M/yr	(MW)	($M)	($M)	$M/yr	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$200	50	$10	$10	$14				$13	$0.009	$0.008	1800	$16	$15	1.000	$16	$15
2015	$204	50	$10	$9	$14	50	$10	$9	$13	$0.009	$0.008	1791	$15	$15	0.926	$14	$14
2016	$208	51	$11	$9	$14	50	$10	$9	$13	$0.009	$0.008	1782	$15	$15	0.857	$13	$13
2017	$212	51	$11	$9	$14	51	$11	$9	$13	$0.009	$0.008	1773	$15	$15	0.794	$12	$12
2018	$216	52	$11	$8	$14	51	$11	$8	$13	$0.009	$0.008	1764	$15	$15	0.735	$11	$11
2019	$221	52	$11	$8	$14	52	$11	$8	$13	$0.008	$0.008	1755	$15	$15	0.681	$10	$10
2020	$225	53	$12	$7	$14	52	$12	$7	$13	$0.008	$0.008	1747	$15	$15	0.630	$9	$9
2021	$230	53	$12	$7	$14	53	$12	$7	$13	$0.008	$0.008	1738	$15	$15	0.583	$9	$8
2022	$234	54	$13	$7	$14	53	$12	$7	$13	$0.008	$0.008	1729	$14	$14	0.540	$8	$8
2023	$239	54	$13	$6	$14	54	$13	$6	$13	$0.008	$0.008	1721	$14	$14	0.500	$7	$7
2024	$244	55	$13	$6	$14	54	$13	$6	$13	$0.008	$0.008	1712	$14	$14	0.463	$7	$7
2025	$249	55	$14	$6	$14	55	$14	$6	$13	$0.008	$0.008	1703	$14	$14	0.429	$6	$6
2026	$254	56	$14	$6	$14	55	$14	$6	$13	$0.008	$0.008	1695	$14	$14	0.397	$6	$6
2027	$259	56	$15	$5	$14	56	$14	$5	$13	$0.008	$0.008	1686	$14	$14	0.368	$5	$5
2028	$264	57	$15	$5	$14	56	$15	$5	$13	$0.008	$0.008	1678	$14	$14	0.340	$5	$5
2029	$269	57	$15	$5	$14	57	$15	$5	$13	$0.008	$0.008	1670	$13	$14	0.315	$4	$4
2030	$275	58	$16	$5	$14	57	$16	$5	$13	$0.008	$0.008	1661	$13	$14	0.292	$4	$4
2031	$280	59	$16	$4	$14	58	$16	$4	$13	$0.008	$0.008	1653	$13	$14	0.270	$4	$4
2032	$286	59	$17	$4	$14	59	$17	$4	$13	$0.008	$0.008	1645	$13	$14	0.250	$3	$3
2033	$291	60	$17	$4	$14	59	$17	$4	$13	$0.008	$0.008	1636	$13	$14	0.232	$3	$3
2034	$297	60	$18	$4	$14	60	$18	$4	$13	$0.008	$0.008	1628	$13	$14	0.215	$3	$3
2035	$303	61	$18	$4	$14	60	$18	$4	$13	$0.008	$0.008	1620	$13	$14	0.199	$3	$3
2036	$309	62	$19	$4	$14	61	$19	$3	$13	$0.008	$0.008	1612	$13	$13	0.184	$2	$2
2037	$315	62	$20	$3	$14	62	$19	$3	$13	$0.008	$0.008	1604	$12	$13	0.170	$2	$2
2038	$322	63	$20	$3	$14	62	$20	$3	$13	$0.008	$0.008	1596	$12	$13	0.158	$2	$2
2039	$328					63	$21	$3									
				$149				$140									

Validation: Present Value	$166	$166

PV is assumed to be installed in sufficient capacity to allow this investment stream to be deferred for one year. The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Utility costs are calculated using the difference between the amortized costs of the conventional plan and the amortized cost of the deferred plan. For example, the utility cost for 2022 is ($14M - $13M)/54MW x 1000 W/kW = $14 per effective kW of PV. As before, utility prices are back calculated using the PV production and the VOS component rate is calculated such that the total discounted amount equals the discounted utility cost.

Location-specific Avoided Costs

As an alternative to system-wide costs for distribution, location-specific costs may be used. When calculating location-specific costs, the calculation should follow the same method of the system-wide avoided cost method, but use local technical and cost data. The calculation should satisfy the following requirements:

- The distribution cost VOS should be calculated for each distribution planning area, defined as the minimum area in which capacity needs cannot be met by transferring loads internally from one circuit to another.
- Distribution loads (the sum of all relevant feeders), peak load growth rates, and capital costs should be based on the distribution planning area.
- Local Fleet Production Shapes may be used, if desired. Alternatively, the system-level Fleet Production Shape may be used.
- Anticipated capital costs should be evaluated based on capacity related investments only (as above) using budgetary engineering cost estimates. All anticipated capital investments in the planning area should be included. Planned capital investments should be assumed to meet capacity requirements for the number of years defined by the amount of new capacity added (in MW) divided by the local growth rate (MW per year). Beyond this time period, which is beyond the planning horizon, new capacity investments should be assumed each year using the system-wide method.
- Planning areas for which engineering cost estimates are not available may be combined and the VOS calculated using the system-wide method.

Avoided Environmental Cost

Avoided environmental costs are based on the federal social cost of CO_2 emissions[15] plus the Minnesota PUC-established externality costs for non-CO_2 emissions[16].

The externality cost of CO_2 emissions shown in Table 5 are calculated as follows. The EPA externality cost estimated for a given year is published in 2007 dollars per metric ton. These costs are adjusted for inflation (converted to current dollars), converted to dollars per short ton, and then converted to cost per unit fuel consumption using the assumed values in Table 16. For example, the EPA externality cost for 2020 (3.0% discount rate, average) is $43 per metric ton of CO_2 in 2007 dollars. This is converted to 2013 dollars by multiplying by a CPI adjustment factor of 1.13, then converted to dollars per short ton by dividing by 1.102, then escalated using the general escalation rate of 2.37% per year to give $50.73 per ton. This is equivalent to $50.73 *102.250 / 2000 = $2.594 per MMBtu in 2020 dollars.

Table 16. Natural gas emissions.

	NG Emissions (lb/MMBtu)
PM10	0.017
CO	0.008
NO_X	0.026
Pb	0.000
CO_2	102.250

All pollutants other than CO_2 are calculated using the Minnesota externality costs using the following method. Externality costs are taken as the midpoint of the low and high values for the urban scenario, adjusted to current dollars, and converted to a fuel-based value using Table 16. For example, the published costs for PM10 are $6,291 per ton (low case) and $9,056 per ton (high case). These are averaged to be ($6291+$9056)/2 = $7674 per ton. For 2020, these are escalated using the general escalation rate of 2.37% per year to $8,831 per ton, equivalent to $8831 x 0.17 / 2000 = $0.076 per MMBtu. Similar calculations are done for the other pollutants.

In the example shown in Table 17, the environmental cost is the sum of the costs of all pollutants. For example, in 2020, the total cost of $2.684 per MMBtu corresponds to the 2020 total cost in Table 5. This cost is multiplied by the heat rate for the year (see Avoided Fuel Cost calculation) and divided by 10^6 to give the environmental cost in $ per kWh for each year. The remainder of the calculation follows the same method as the avoided variable O&M costs but using the environmental discount factor.

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[15] See http://www.epa.gov/climatechange/EPAactivities/economics/scc.html, EPA technical document appendix, May 2013.
[16] "Notice of Updated Environmental Externality Values," issued June 5, 2013, PUC docket numbers E-999/CI-93-583 and E-999/CI-00-1636.

Table 17. (EXAMPLE) Economic value of avoided environmental cost.

Year	Env. Cost ($/MMBtu)	Heat Rate (Btu/kWh)	Prices Utility ($/kWh)	Prices VOS ($/kWh)	p.u. PV Production (kWh)	Costs Utility ($)	Costs VOS ($)	Discount Factor	Disc. Costs Utility ($)	Disc. Costs VOS ($)
2014	2.017	8000	$0.016	$0.026	1,800	$29	$48	1.000	$29	$48
2015	2.119	7992	$0.017	$0.026	1,791	$30	$47	0.971	$29	$46
2016	2.224	7984	$0.018	$0.026	1,782	$32	$47	0.943	$30	$44
2017	2.333	7976	$0.019	$0.026	1,773	$33	$47	0.915	$30	$43
2018	2.446	7968	$0.019	$0.026	1,764	$34	$47	0.888	$31	$41
2019	2.562	7960	$0.020	$0.026	1,755	$36	$46	0.863	$31	$40
2020	2.684	7952	$0.021	$0.026	1,747	$37	$46	0.837	$31	$39
2021	2.809	7944	$0.022	$0.026	1,738	$39	$46	0.813	$32	$37
2022	2.939	7936	$0.023	$0.026	1,729	$40	$46	0.789	$32	$36
2023	3.073	7928	$0.024	$0.026	1,721	$42	$45	0.766	$32	$35
2024	3.212	7920	$0.025	$0.026	1,712	$44	$45	0.744	$32	$34
2025	3.356	7912	$0.027	$0.026	1,703	$45	$45	0.722	$33	$32
2026	3.505	7905	$0.028	$0.026	1,695	$47	$45	0.701	$33	$31
2027	3.588	7897	$0.028	$0.026	1,686	$48	$45	0.681	$33	$30
2028	3.746	7889	$0.030	$0.026	1,678	$50	$44	0.661	$33	$29
2029	3.909	7881	$0.031	$0.026	1,670	$51	$44	0.642	$33	$28
2030	4.078	7873	$0.032	$0.026	1,661	$53	$44	0.623	$33	$27
2031	4.252	7865	$0.033	$0.026	1,653	$55	$44	0.605	$33	$26
2032	4.433	7857	$0.035	$0.026	1,645	$57	$43	0.587	$34	$25
2033	4.620	7849	$0.036	$0.026	1,636	$59	$43	0.570	$34	$25
2034	4.813	7842	$0.038	$0.026	1,628	$61	$43	0.554	$34	$24
2035	5.013	7834	$0.039	$0.026	1,620	$64	$43	0.538	$34	$23
2036	5.219	7826	$0.041	$0.026	1,612	$66	$43	0.522	$34	$22
2037	5.433	7818	$0.042	$0.026	1,604	$68	$42	0.507	$35	$21
2038	5.654	7810	$0.044	$0.026	1,596	$70	$42	0.492	$35	$21

Validation: Present Value	Utility	VOS
	$809	$809

Avoided Voltage Control Cost

This is reserved for future updates to the methodology.

Solar Integration Cost

This is reserved for future updates to the methodology.

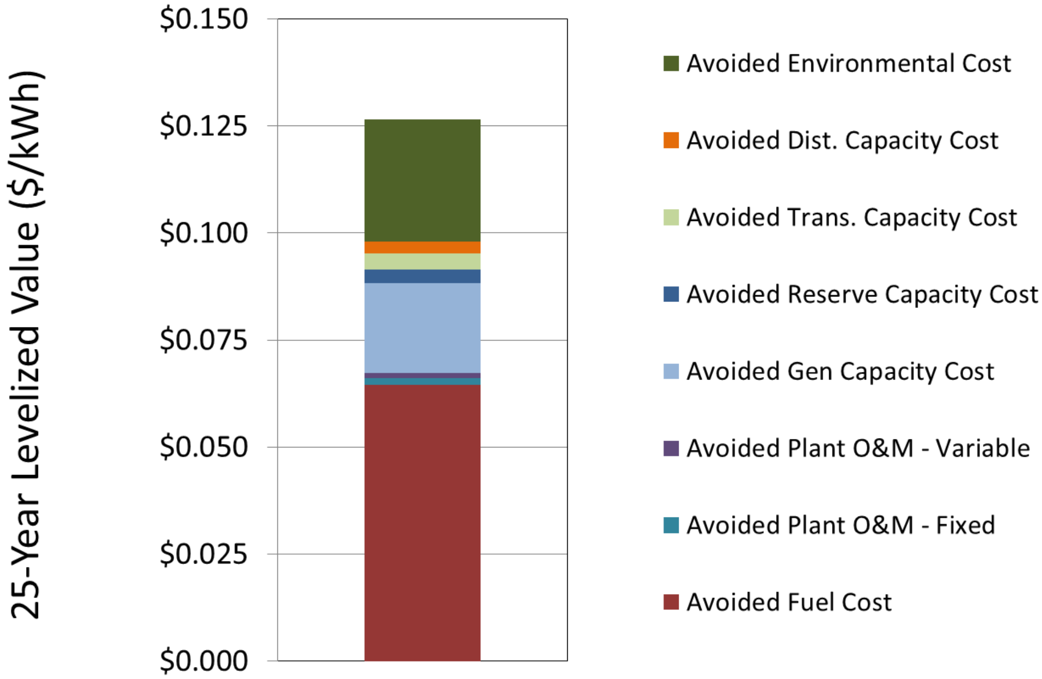
Example Results

The economic value, load match, distributed loss savings, and distributed PV value are combined in the required VOS Levelized Calculation Chart. An example is presented in Figure 2 using the assumptions made for the example calculation. Actual VOS results will differ from those shown in the example, but utilities will include in their application a VOS Levelized Calculation Chart in the same format. For completeness, Figure 3 (not required by the utilities) is presented showing graphically the relative importance of the components in the example.

Figure 2. (EXAMPLE) VOS Levelized Calculation Chart (Required).

25 Year Levelized Value	Economic Value ($/kWh)	Load Match (No Losses) (%)	Distributed Loss Savings (%)	Distributed PV Value ($/kWh)
Avoided Fuel Cost	$0.060		8%	$0.065
Avoided Plant O&M - Fixed	$0.003	40%	9%	$0.001
Avoided Plant O&M - Variable	$0.001		8%	$0.001
Avoided Gen Capacity Cost	$0.048	40%	9%	$0.021
Avoided Reserve Capacity Cost	$0.007	40%	9%	$0.003
Avoided Trans. Capacity Cost	$0.009	40%	9%	$0.004
Avoided Dist. Capacity Cost	$0.008	30%	5%	$0.003
Avoided Environmental Cost	$0.026		8%	$0.029
Avoided Voltage Control Cost				
Solar Integration Cost				
	$0.163			$0.126

Figure 3. (EXAMPLE) Levelized value components.



As a final step, inflation-adjusted VOS amounts can be calculated as shown in the example of Table 18. In this calculation, annual adjustments to the VOS are made using the assumed value of general inflation. The initial value is selected such that the discounted value is equal to the discounted value of the 25-year levelized time series. The inflation-adjusted VOS amounts would be fixed for customers entering the rate schedule in a given year.

Figure 4 illustrates the difference between the levelized VOS and the inflation-adjusted VOS. Initially, the inflation-adjusted VOS is lower than the levelized value, but this is reversed in later years.

Table 18. (EXAMPLE) Calculation of inflation-adjusted VOS.

Year	Discount Factor	Escalation Factor	Example VOS (Levelized)	Disc.	Example VOS (Inflation Adj.)	Disc.
2014	1.000	1.000	0.126	0.126	0.103	0.103
2015	0.926	1.024	0.126	0.117	0.105	0.098
2016	0.857	1.048	0.126	0.108	0.108	0.093
2017	0.794	1.073	0.126	0.100	0.111	0.088
2018	0.735	1.098	0.126	0.093	0.113	0.083
2019	0.681	1.124	0.126	0.086	0.116	0.079
2020	0.630	1.151	0.126	0.080	0.119	0.075
2021	0.583	1.178	0.126	0.074	0.121	0.071
2022	0.540	1.206	0.126	0.068	0.124	0.067
2023	0.500	1.235	0.126	0.063	0.127	0.064
2024	0.463	1.264	0.126	0.059	0.130	0.060
2025	0.429	1.294	0.126	0.054	0.133	0.057
2026	0.397	1.325	0.126	0.050	0.136	0.054
2027	0.368	1.356	0.126	0.046	0.140	0.051
2028	0.340	1.388	0.126	0.043	0.143	0.049
2029	0.315	1.421	0.126	0.040	0.146	0.046
2030	0.292	1.455	0.126	0.037	0.150	0.044
2031	0.270	1.489	0.126	0.034	0.153	0.041
2032	0.250	1.524	0.126	0.032	0.157	0.039
2033	0.232	1.560	0.126	0.029	0.161	0.037
2034	0.215	1.597	0.126	0.027	0.165	0.035
2035	0.199	1.635	0.126	0.025	0.168	0.033
2036	0.184	1.674	0.126	0.023	0.172	0.032
2037	0.170	1.714	0.126	0.022	0.177	0.030
2038	0.158	1.754	0.126	0.020	0.181	0.028
				1.458		1.458

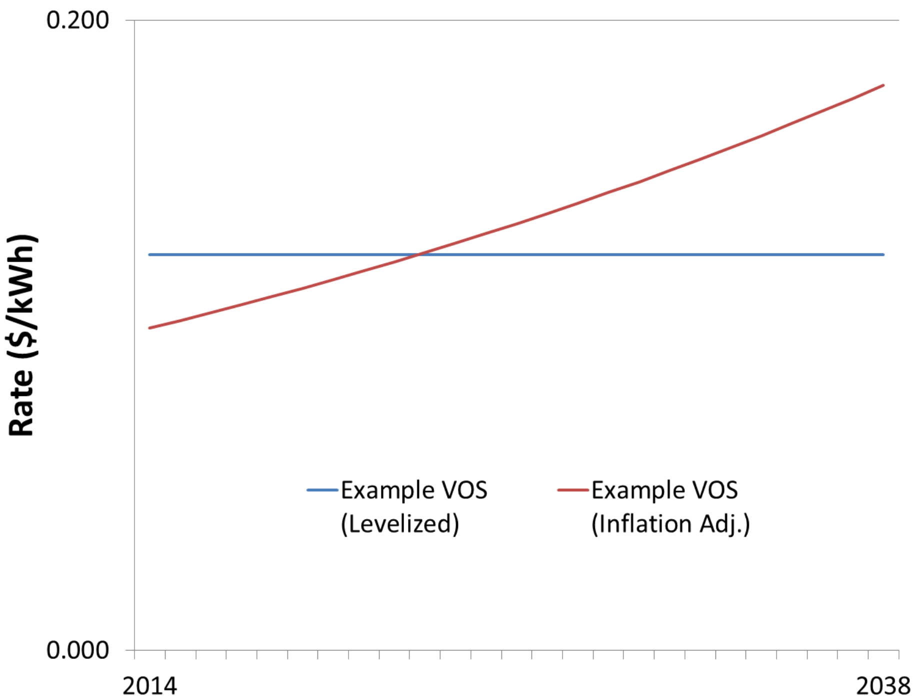


Figure 4. (EXAMPLE) Levelized VOS versus inflation-adjusted VOS.